OOC GMG290000 2012 Renewal – List of Past EPA Determinations from OOC Environmental Sub-Committee

Rev. 0 7/15/2011

No.	Type/Category	Permit Section Ref.	Comments	Past Determination
1	Misc. Discharges - Subsea Wireline Discharge		OOC is not proposing any permit action. This information is being supplied for informational purposes only. However, if EPA would like to include in the forthcoming permit renewal, OOC fully supports the inclusion.	Discharge of wireline lubricator grease authorized under "Blowout Preventer Fluid". See attached email for EPA Determination: Item #4 - Subsea Wireline Grease discharge.txt
2	Well Fluids		OOC is not proposing any permit action. This information is being supplied for informational purposes only. However, if EPA would like to include in the forthcoming permit renewal, OOC fully supports the inclusion.	Discharge of proppant containing trace radioactive material authorized as discharge of a well treatment fluid. See attached letter for EPA Determination: Radioactive Proppant.zip
3	Sub-Sea Leak Tracer Dyes	I.B.10.a	OOC is not proposing any permit action. This information is being supplied for informational purposes only. However, if EPA would like to include in the forthcoming permit renewal, OOC fully supports the inclusion.	Toxicity testing of powdered dyes in "as-used" condition versus "neat" in meeting standards at GMG 290000 Part I.B.10.a. This approach was discussed (via email) with Phil Jennings USEPA VI on 02/12/09. Email attached: FW New Qustion Sub Sea Test Dyes Liquids versus Solids.txt
4	Produced Water		OOC is not proposing any permit action. This information is being supplied for informational purposes only. However, if EPA would like to include in the forthcoming permit renewal, OOC fully supports the inclusion.	Discharge of salt slurry generated from MEG unit authorized for discharged as produced water if meets permit requirements for produced water. This was discussed in meeting with Isaac Chen and Brent Larson USEPA VI on March 23, 2011 (See attached email summarizing meeting) and via email (also attached) with Scott Wilson USEPA VI on December 3, 2008. Emails Attached: EPA Meeting to discuss MEG Reclamat

No.	Type/Category	Permit Section Ref.	Comments	Past Determination
				RE Salt slurry from MEG regeneration system.msg
5	Reference Papers/Studies		OOC is not proposing any permit action. This information is being supplied for informational purposes only. However, if EPA would like to include in the forthcoming permit renewal, OOC fully supports the inclusion.	The following are past studies that have demonstrated that under Gulf of Mexico conditions, produced water discharges are rapidly diluted below the threshold concentrations for chronic toxicity and that produced water components are not taken up by, and pose minimal risk to, marine organisms living near produced water discharge points: • Continental Shelf Associates (1997); "Radionuclides, Metals and Hydrocarbons in Oil and Gas Operational Discharges and Environmental Samples Associated with Offshore Production Facilities on the Texas Louisiana Continental Shelf with an Environmental Assessment of Metals and Hydrocarbons" Report prepared for the US Department of Energy • OOC. 1997. Gulf of Mexico Produced Water Bioaccumulation Study. Conducted by Continental Shelf Associates, Jupiter, FL. for Offshore Operators Committee, P.O. Box 50751, New Orleans, LA., 70150. • Smith, J.P., Brandsma, M.G., Nedwed, T.J. (2001); "Field Verification of the Offshore Operators Committee (OOC) Mud and Produced Water Discharge Model" , Environmental Modeling and Software" (2004) Vol 19 pp 739-750. • Smith, J.P., Mairs, H.L., Brandsma, M.G., Meek, R.P., Ayers, R.C. Jr. (1994)"Field Validation of the Offshore Operators Committee (OOC) Produced Water Discharge Model" SPE Paper 28350 presented at the SPE 69th Ann. Tech. Conf. Exhib., New Orleans, LA, September 25-28 1994
6	General		See Permit Revision Listing for more specific information on proposed permit changes.	OOC has developed a Permit Revision Listing that provides proposed revisions and clarifications to the current permit.

OOC GMG290000 2012 Renewal – Permit Revisions/Clarifications List

Rev. 0 7/15/2011

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
1	Produced Water	I.B.4.a	Intentionally Blank	Seawater Addition to produced water - OOC is not proposing any additions or deletions to the existing permit language. We are only providing historical information on seawater addition to produced water. • The provisions for multi port diffusers and the addition of seawater were added to the permit in the 12/3/93 edition (FR 58, No. 231 pg. 63964). • Comment No. 7 and EPA response of attached 1993 response to comments provide information related to EPA's justification for seawater addition: Response to Comments.ZIP No such practice in TX territorial seas — no discharge of PW Few facilities were designed for mixing of PW & Seawater • A summary of Technology-based and Water Quality-based Limits in NPDES Permits and their relation to seawater addition of PW is provided below: OOC Seawater Dilution Paper Final 0:
2	Definitions	Part II.G and Part I.B.4.b.vi	New definition to be added in Part II.G: "Hydrate control fluids" means fluids used to prevent or retard the formation of hydrates in and on process equipment and piping. Hydrate control fluids are not considered treatment chemicals. Also revise Part I.B.4.b.vi: Samples for monitoring produced water toxicity shall be collected after addition of any added substances….. Samples also shall be representative of produced water discharges when hydrate inhibitors, scale inhibitors, corrosion inhibitors, biocides, paraffin inhibitors, well completion fluids, workover fluids, and/or well treatment fluids are used in operations.	See attached OOC Hydrate Control White Paper for additional information. Adding a definition of hydrate control fluids to the permit will clarify the difference in use between these fluids and treatment chemicals. Revising the language at Part I.B.4.b.vi clarifies that these fluids are also used internally in the process and can partition to produced water. These clarifications are supported – for example-by APC communication with EPA (Wilson, Chen, Houston) 7April, 2010: "50/50 MEG and seawater mixture is allowed to be discharged as a hydrate control fluid subsea or at a production facility after hydrotesting if the NPDES monitoring requirements for miscellaneous discharges of subsea fluids are complied with under the permit. Scott Wilson confirmed that hydrate control fluid does not fit the chemically treated miscellaneous discharge category in the NPDES General Permit and that chemically treated miscellaneous discharges were meant for biocides and corrosion inhibitors." See attached OOC Hydrate Control White Paper for additional information.

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
				OOC Hydrate Paper REV 7 - 4-7-11.pdf
3	WBM/Well Treatment/Completion/Workover Fluids	I.C. & II.G	Add new section: I.C.7 Unmixed Chemicals or Products There shall be no discharge of any chemical or product not already mixed for use in any waste stream. Such unused chemicals or products shall be shipped onshore for final disposal or reuse. Revise Definitions as follows II.G. as follows: 31. "Drilling Fluid" means the circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure (or to test proper operation of mud handling systems or mixed excess fluids) Classes of drilling fluids are:... 36. "Excess Cement Slurry" means the excess mixed cement, including additives and wastes from equipment washdown, after a cementing operation (or cement slurry used to test proper operation of cement handling equipment.) 17. "Completion Fluids" means salt solutions, weighted brines, polymers and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production (or used for testing fluid handling equipment.) These fluids move into the formation and return to the surface as a slug with the produced water; (or mixed excess fluids.).... 86. "Well Treatment Fluids" mean any fluid used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled; (or used for testing fluid handling equipment.) These fluids move into the formation and return to the surface as a slug with the produced water; (or mixed excess fluids) Stimulation fluids include substances such as acids, solvents, and propping agents. 87. "Workover Fluids" mean salt solutions, weighted brines,	Typically in offshore operations, fluids volumes in excess of the estimated requirements for a job are prepared for use. Although every effort is made- for cost, space, weight and marine transportation reasons- to minimize any excess fluid volumes, it is not practical to eliminate all excess volumes due to the need to have a contingency volume immediately available in order to maintain primary well control in the event losses to the formation are incurred. Also, in the case of riserless drilling, contingency volumes are required to offset slower than expected penetration rates and/or hole problems that require additional circulation and the resultant fluid volumes. Additionally, during some well operations (most commonly during completions where the weight of the fluid is based on fluid composition and does not utilize weighting agents in order to prevent formation impairment) it is sometimes recognized after the start of the job that a different fluid is required due to encountering unexpected formation pressures - this renders the previously prepared/mixed fluid obsolete. Secondly, new equipment, systems or facilities typically must be commissioned. This includes testing equipment with the fluids that will actually be handled to ensure functionality, etc. As above, every effort is made- for cost, space, weight and marine transport reasons- to minimize the amounts of fluids prepared. Once the above fluids are accumulated, they may be managed via onshore reuse/recycle or disposal. Except for fluids of very high value (e.g. very dense well control brines), or fluids which have not been mixed (and so can be returned to the vendor) onshore disposal is the only cost effective management option. Reuse in another offshore job is also considered but due to competition between activities for space and weight on offshore facilities, and mixed fluid "shelf lives", it is often not feasible to hold fluids offshore for any length of time. Onshore disposal consists of testing, solidification and landfilling at permitted facilities. To allow flexibility in management of these fluids as well as reduce transportation risks and onshore consumption of landfill capacity, the OOC proposes that the Agency adopt the language existing in the Region 4 OCS NPDES General Permit regarding unmixed fluid discharge (see GEG 460000 Part I.C.6) and revising other affected definitions. As noted above, unmixed chemicals/products can typically be returned to vendors. Under the OOC proposal,, mixed fluids that comply with the monitoring provisions applicable to the fluid could be discharged (e.g. mixed completion fluids would be monitored as a completion fluid discharge; water based muds would be monitored as a water based mud discharge, etc). The permit currently authorizes discharge of mixed, used fluids: allowing the discharge of mixed but unused fluids of the same type (and subject to the same limits/monitoring) is protective since unused fluids have not been exposed to many of the hydrocarbon-based

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
			polymers, and other specialty additives used in a producing well to allow safe repair and maintenance or abandonment procedures; or used for testing fluid handling equipment or mixed excess fluids. High solids drilling fluids used during workover operations are not considered workover fluids by definition and therefore must meet drilling fluid effluent limitations before discharge may occur. Packer fluids, low solids fluids between the packer, production string and well casing, are considered to be workover fluids and must meet only the effluent requirements imposed on workover fluids.	pollutants regulated by the permit. Finally, as regards fluids used for equipment testing, the requested authorization is consistent with the permit requirements for Proper Operation and Maintenance under Part II.B.3. Past determinations from EPA that support this change include: 1. Cement and waterbased mud used in commissioning activities (Nelson Smith EPA to Larry Henry Chevron, 1998): Excess Cement Slurry from Equip Tes 2. Excess cement used for commissioning activities (Brian Mueller, EPA to Carlos Moreno, BP, 2009 FW Question about excess cement slurry.msg To implement this recommendation, the various related portions of the permit are revised as shown at left.
4	Misc. Chemically treated SW & FW	I.B.11 & II.G	**Revise Part I.B.11 to delete the examples given.** **Add a new definition as follows in Part II.G** Chemically Treated Waters: any fresh or seawater discharge to which treatment chemicals have been added. These include, but are not limited to: • Excess seawater which permits the continuous operation of fire control and utility lift pumps • Excess seawater from pressure maintenance and secondary recovery projects • Water released during training of personnel in fire protection • Seawater used to pressure test new and existing piping and	There are additional types of chemically treated waters than those currently listed in the permit. However they are not qualitatively different from those listed in the permit (i.e. similar chemical treatments are used). OOC requests the proposed change to recognize this. Treatment chemicals such as corrosion inhibitors, biocides, etc. are added to seawater/freshwater for piping and equipment preservation in order meet permit conditions for proper operation and maintenance of equipment. Examples of other discharges would include: 1) chemically treated seawaters/freshwaters used for preparing equipment to be placed out of service (treated with small amounts of corrosion inhibitors, biocide, etc. for piping and equipment preservation) 2) drainage of the chemically treated freshwater from closed loop heat transfer systems (treated with small amounts of corrosion inhibitors, scale inhibitors, etc for piping and equipment preservation) 3) various treated seawaters/freshwaters used in commissioning of new equipment (treated with small amounts of corrosion inhibitors, scale inhibitors, biocide, etc for piping and equipment preservation)

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
		~~Added~~ New New	pipelines • Ballast water • Once Through Non-contact cooling water • Seawater used during Dual Gradient Drilling • Seawater/freshwater used as piping and equipment preservation fluid Discharges associated with operation and maintenance of hypochlorite generating units and desalination units are not considered chemically treated.	The exclusion of operating and maintenance discharges from hypochlorite and desalination systems is based on the prior exclusion of these routine streams from toxicity testing in the reissuance of the permit in October 2007. Additionally, chemically treated seawater may need to be used in Dual Gradient Drilling in order to properly operate and maintain equipment and piping. What is Dual Gradient Drilling (DGD)? • The practice of maintaining two effective fluid gradients in the wellbore annulus while drilling. • This results in an annular gradient which is a combination of the two fluid gradients associated with the two different density fluids in the annulus. • The resultant dual gradient fluid exerts the same BHP as the equivalent single gradient fluid. • Typically the drill string would have a single "denser" gradient. • In DGD, there is one denser gradient below the sea floor, another less dense gradient above the sea floor (seawater). • Refer to attached diagram for more details. The Dual Gradient Drilling technology is becoming more common in the Gulf of Mexico. There are two seawater discharges associated with DGD: • Seawater used to provide hydraulic power to Mud Lift Pumps used in Dual Gradient Drilling • Seawater used to provide static head in riser during Dual Gradient Drilling The heart of the DGD technology is the Mud Lift Pump (MLP) which provides the pumping power to transport mud and cuttings from the sea floor to the rig through a riser auxiliary line called the Mud Return Line. The MLP is a positive displacement pump that is driven by seawater derived from the rig sea chest. Typically, the system has three dedicated pumps on the rig to provide the required power to the MLP. The number of pumps may vary depending on the system. The sea water is pumped through a Seawater Power Fluid Filtration Skid (SWPF) a sea water reserve tank and then down a riser auxiliary line called the Seawater Power Fluid Line (SPFL). Once the seawater provides the required power to the MLP it is discharged to the sea about 100 feet above the mudline. The seawater does not come into contact with drilling fluids or cuttings. There are three discharge points on the MLP pumps called seawater choke outlets. Number of chokes may vary depending on the system. These choke outlets can be used in different configurations to discharge seawater depending on drilling activities. Seawater discharge rates will vary based on the systems. Seawater discharge rates will be 10% higher than the drilling rates.

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
				Depending on the system design, corrosion inhibitors and biocides may need to be used to prevent corrosion and properly operate and maintain the Dual Gradient Drilling system. Dual Grad Pic.docx DGD Seawater Flow Path
5	Misc. Chemically Treated SW & FW	I.B.11.b & II.G.81	Delete from I.B.11.b) as follows: ~~Miscellaneous discharges of seawater and freshwater to which chlorine or hypochlorite, have been added are excluded from this monitoring provision.~~ Revise I.G.81) as follows: "Treatment Chemicals" means biocides, corrosion inhibitors, or other chemicals which are used to treat seawater or freshwater to prevent corrosion or fouling of piping or equipment. Non-toxic scale inhibitors; dyes; chlorine; and bromide antifouling treatments are not considered treatment chemicals. ~~However,~~ This includes chlorine generated using an electric current rather than added~~. is considered a treatment chemical."~~	Bromide treatment is sometimes used offshore (e.g. firewater pumps equipped with bromide cartridges that may have trace amounts of bromide discharged from water released during training of personnel in fire protection). EPA has previously found these miscellaneous discharges to be similar to hypochlorite-treated discharges and subject to the same monitoring exclusion. EPA Determination Attached: Bromide Treatment.txt The permit writer previously acknowledged a typographical error in the 2007 issuance of the permit, regarding chlorine generated using an electric current, which should be corrected now. It currently states the opposite of what the permit writer intended.
6	Misc. discharges	I.B.10.a & II.G.84	Revise I.B.10.a) as follows: [Exceptions] Uncontaminated seawater, uncontaminated freshwater, source water and source sand, uncontaminated bilge water, and uncontaminated ballast water may be discharged from platforms that are on automatic purge systems without monitoring for free oil when the facilities are not manned. Additionally, discharges at the sea floor of uncontaminated seawater muds and cuttings prior to installation of the marine riser, cement, blowout preventer fluid, sub sea wellhead preservation fluids, sub sea production control fluid, umbilical steel tube storage fluid, leak tracer fluid, and riser tensioner fluids may be discharged without monitoring with the static sheen	What is Dual Gradient Drilling (DGD)? • The practice of maintaining two effective fluid gradients in the wellbore annulus while drilling. • This results in an annular gradient which is a combination of the two fluid gradients associated with the two different density fluids in the annulus. • The resultant dual gradient fluid exerts the same BHP as the equivalent single gradient fluid. • Typically the drill string would have a single "denser" gradient. • In DGD, there is one denser gradient below the sea floor, another less dense gradient above the sea floor (seawater). • Refer to attached diagram for more details. The Dual Gradient Drilling technology is becoming more common in the Gulf of Mexico. There

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
			test when conditions make observation of a visual sheen on the surface of the receiving water impossible. Discharges of muds, cuttings, and cement at the seafloor before installation of the marine riser are exempted from the free oil limitation. Revise II.G.84 as follows: 84. "Uncontaminated Seawater" means seawater which is returned to the sea without the addition of treatment chemicals. Included are (1) discharges of excess seawater which permit the continuous operation of fire control and utility lift pumps (2) excess seawater from pressure maintenance and secondary recovery projects (3) water released during the training and testing of personnel in fire protection (4) seawater used to pressure test or flush new or existing piping and pipelines, (5) once through noncontact cooling water which has not been treated with biocides, (6) seawater used during Dual Gradient Drilling.	are two seawater discharges associated with DGD: • Seawater used to provide hydraulic power to Mud Lift Pumps used in Dual Gradient Drilling • Seawater used to provide static head in riser during Dual Gradient Drilling The heart of the DGD technology is the Mud Lift Pump (MLP) which provides the pumping power to transport mud and cuttings from the sea floor to the rig through a riser auxiliary line called the Mud Return Line. The MLP is a positive displacement pump that is driven by seawater derived from the rig sea chest. Typically, the system has three dedicated pumps on the rig to provide the required power to the MLP. The number of pumps may vary depending on the system. The sea water is pumped through a Seawater Power Fluid Filtration Skid (SWPF) a sea water reserve tank and then down a riser auxiliary line called the Seawater Power Fluid Line (SPFL). Once the seawater provides the required power to the MLP it is discharged to the sea about 100 feet above the mudline. The seawater does not come into contact with drilling fluids or cuttings. There are three discharge points on the MLP pumps called seawater choke outlets. Number of chokes may vary depending on the system. These choke outlets can be used in different configurations to discharge seawater depending on drilling activities. Seawater discharge rates will vary based on the systems. Seawater discharge rates will be 10% higher than the drilling rates. Depending on the system design, corrosion inhibitors and biocides may need to be used to prevent corrosion and properly operate and maintain the Dual Gradient Drilling system. Dual Grad Pic.docx DGD Seawater Flow Path

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
7	Misc. Discharges	I.B.10 & II.G	Revise I.B.10) as follows: Add the following discharge to list: Pre-toxicity test Pipeline Brines Add definition to II.G : "Pipeline Brines" means salt solutions and weighted brines used during pipeline commissioning for hydrotesting, or flowline preservation.	Brine is used as a commissioning fluid in certain applications for two primary reasons. 1) Instead of hydrotesting with seawater, which often requires the use of treatment chemicals to protect the pipe from corrosion, brine can be left in place with no additional chemicals. 2) Brine may inhibit hydrate formation when production fluids will be commingled with the pipeline fluid. 7-day Toxicity before apply Discharge Rate limit to NOEC Due to the properties of the brine, no biocide or corrosion inhibitor is needed to protect the pipe. The brine can be left in place indefinitely, whereas chemicals require a known period of preservation when introduced into the pipe. The preservation properties of brine allow for schedule changes to occur without further interventions on the hydrotested pipe. Operators sometimes prefer not to use treatment chemicals where possible because of difficulty in monitoring chemically-treated discharges (collecting subsea samples for toxicity). Use of untreated water is not a recommended practice due to the threat of corrosion while the water is in the pipe.
8	Miscellaneous discharge	I.B.10 & II.G	<u>**Revise Part I.B.10 as follows:**</u> **10. Miscellaneous Discharges** Desalinization Unit Discharge Diatomaceous Earth Filter Media Blowout Preventer Control Fluid Uncontaminated Ballast Water Uncontaminated Bilge Water Mud, Cuttings, and Cement at the Seafloor Uncontaminated Freshwater Uncontaminated Seawater Boiler Blowdown Source Water and Sand Excess Cement Slurry Sub sea Wellhead Preservation Fluids Sub sea Production Control Fluid Hydrate Control Fluid Umbilical Steel Tube Storage Fluid Leak Tracer Fluid Riser Tensioner Fluids Bulk Transfer Operations Powder <u>Add definition to II.G</u> : "Bulk Transfer Operations Powder" means de minimis amounts of bulk product (e.g. barite, cement, etc.) that may be released-during transfers from supply boats to a drilling rig.	During bulk transfer of solid products (e.g. barite, cement) from a boat to a rig, vents are opened on the rig tanks to allow for pressurized air to escape from the receiving container/tank. Typically, trace amounts of the product being transferred will escape from the vents as dust. This discharge is consider a de minimus loss which quickly disperses with no impairment to the receiving waters. These discharges are expected to represent a small fraction of the barite/cement discharges already authorized under the permit for water based muds and excess cement slurry, respectively. OK for dust falls into water directly. No discharge of collected powder. EPA Region 4 approved this as a miscellaneous discharge in the 4/1/10 re-issuance of GEG 460000 as a Miscellaneous discharge ("Bulk Transfer Operations Powder") OOC is requesting this provision be added to the permit as shown.
9	Misc. Discharges	I.B.10.a. & I.D.15	Revise Part I.B.10 a) as follows:	Other permit limit toxicity requirements describe averaging methods to use when reporting multiple results, but not the sub sea fluid toxicity requirements.

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
			If the effluent fails the survival or sub-lethal test endpoint ~~in any test~~, any discharge associated with use of the product will be considered to ~~be~~ in violation of this permit. See Sampling Protocol in Part I.D.15. ? Add Part I.D.15 as follows: I.D.15. Sampling Protocol for Miscellaneous Discharge Sub Sea Fluid Toxicity Test Compliance with the 50 mg/L minimum NOEC permit limit shall be based on the arithmetic average of up to three test results from the same production lot. The first sample must be split into two aliquots (e.g., 1A and 1B) and analyzed separately. The second sample (2) shall be a backup sample, collected within 15 minutes of the first sample, from the same production lot, and shall be retained following proper storage and handling procedures. Permittees shall show compliance based on results from 1A, or from the arithmetic average of 1A and 1B, or from the arithmetic average of 1A, 1B, and 2. All test results obtained shall be submitted with the DMR and all NOECs shall be rounded to the nearest mg/L.	Sub sea fluid toxicity tests use the product as supplied because these minor subsea discharges cannot be sampled. These products are inherently stable, so they are more similar to sediment toxicity test samples than to produced water toxicity test samples. product shall not be used if it couldn't pass NOEC. Test prior to application The proposed additional permit language uses the I.D.9. permit language for averaging sediment toxicity tests, but modified from the sediment toxicity ratio to the arithmetic average used for the toxicity NOEC in other part of the permit .
10	Cooling water Intake	I.B.12.d	**Revise all sections (New fixed and Non-fixed with and without seachests) with below language as follows:** Beginning two years after the effective date of this permit, the operator must conduct either visual inspections or use remote monitoring devices during the period the cooling water intake structure is in operation. The operator must conduct visual inspections at least weekly, or at a lesser frequency as approved by the director, to ensure that the required design and construction technologies are maintained and operated so they continue to function as designed. Alternatively, the operator must inspect using remote monitoring devices to ensure that the impingement and entrainment technologies are functioning as designed. The use of other technologies may be approved by the director in lieu of visual inspections (direct or remote) for safety or technical reasons.	In 2009, OOC sponsored a review of remote monitoring techniques (OOC, 2009) that could be used to address the permit requirements at Part I.B.12.d for monitoring. This review was submitted to EPA region 6 under separate cover (Joe Smith, April, 2011). Additionally, as Operators and Owners have started to plan for the monitoring for new facilities, concerns have arisen over the technical and safety aspects of meeting the visual (direct or remote) monitoring requirement. These are discussed below and reflect comments previously provided on the issue to Region 6 (email from J. Smith, Exxon to I. Chen, EPA 4/14/11). Operators of mobile offshore drilling units have concerns that visual inspection of intakes either by divers or by remotely operated vehicles (ROVs) requires that drilling activities be shut down on dynamically positioned drill ships because safety concerns make it impossible to have divers in the water or to operate ROVs near the ocean surface when the thrusters required for dynamic positioning are in operation. Drilling rig operators suggest that routine monitoring be conducted by measurements with remote monitoring equipment that senses the flow rate and velocity through the intakes and that actual visual monitoring be conducted during planned periods of no drilling or transit activity (e.g. routine shipyard maintenance periods or when loitering at sea between jobs).It is noted that due to the inherent variability of rig scheduling (e.g. due to contract, technical, logistical issues), the periods available to visually monitor intakes can be somewhat difficult to predict. Given that instrumentation provides an alternative

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
				means of sensing fact velocity, this suggests that the frequency of required direct visual monitoring requirements be practically based on 6 month or annual periods for dynamically positioned rigs. Operators of fixed production facilities have concerns that fixed production facilities do not have permanently installed ROVs. Making weekly inspections with ROVs or Divers would require hiring vessel-based ROVs/Divers. This would be costly in both cases but for Divers it would also present real safety concerns.. Additionally, these vessels are not always readily Available, and since they are vessel-based, are subject to limitations imposed by sea state and weather. Alternately, Operators commented that the expense, maintenance costs, and manpower time associated with deploying a camera at the frequency of once per week would be burdensome, and would add minimum value. Of more concern, there are questions about how to ensure the camera is not drawn into an operating water intake. If the intake were blocked, flow could be degraded which could impair fire fighting ability, process operations or cooling demands. Any of these could result in shutdowns and their associated risks and lost production. OOC is engaging BOEMRE to understand any concerns or constraints hey may have with such inspection practices. Operators believe that using remote monitoring devices intended to determine flow velocity through the intake are more practical and actually provide a better indication of any blockage that could potentially increase intake face velocity and thus increase the potential for impingement. Operators of fixed production facilities have also suggested that, when necessary, visual inspections by divers or ROVs can be scheduled during planned maintenance periods to augment the information provided by remote (non-visual) monitoring. Related to the above, OOC recognizes that regulations address impingement of marine life on intake screens as well as entrainment in cooling water intakes. We believe that the existing limitation of intake face velocity to 0.5 ft/s represents the best available technology for preventing losses due to impingement. During our discussions of the plans for the entrainment monitoring program, we submitted to Region 6 information from the scientific literature indicating that almost all species of fish at life stages large enough to be impinged are able to swim at speeds in excess of 0.5 ft/s and should be able to avoid the very limited volume of water column where such speeds exist (Smith, 2009). Accordingly, we believe that limiting the face velocity of intakes represents the best approach to minimizing impingement. The importance of intake velocity was recognized by EPA in the recently published fact sheet on the proposed new cooling water intake structure regulation (EPA, 2011), where it was stated that "Alternately, the facility could reduce their intake velocity to 0.5 feet per second. At this rate, most of the fish can swim away from the cooling water intake of the facility." References EPA (2011); "Proposed Regulations to Establish Requirements for Cooling Water Intake

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
				Structures at Existing Facilities" Fact Sheet EPA 820-F-11-002 accessed April 8, 2011 at http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/factsheet_proposed.pdf OOC(2009); "Review of Techniques for Remote Monitoring of Cooling Water Intakes Relevant to Visual Inspection Requirements", report prepared by Alden Research Laboratory for the Offshore Operators Committee, September 2009. Smith, J.P. (2009); "Response to EPA Comments Dated November 13, 2009 Concerning Plans for an Industry Wide Entrainment Monitoring Study", memorandum to Isaac Chen dated December 1, 2009; attached (file Resp11_13_09comments.pdf) to email from joe.p.smith@exxonmobil.com dated December 10, 2009.
11	"De Minimis" Discharges	I.B.2	Revise I.B.2 as follows: De Minimis Discharges of Non aqueous Based Drilling Fluids. De minimis discharges of non aqueous based drilling fluids not associated with cuttings shall be contained to the extent practicable to prevent discharge. Allowable de minimis discharges can include wind blown drilling fluids from the pipe rack, residual drilling fluids that are adhered to marine risers, diverter systems testing, and BOPs after fluid displacement, and minor drips and splatters around mud handling and solids control equipment. Such de minimis discharges are not likely to be measurable and are not considered in the base fluids retained on cuttings limit.	OOC requests that it be made explicit in the permit that residual fluid releases of drilling fluids from marine risers, diverter systems and BOPs be classified as 'de minimis'. Two of these discharges were previously determined to be 'de minimis' by EPA in the Synthetic Based Muds Q&A. (http://www.epa.gov/earth1r6/6en/w/offshore/sbm_qa.htm) Marine Riser (from SBM Q&A) Question: After displacement of SBM in the marine riser with seawater (prior to disconnect) can the seawater with residual SBM that was adhered to the interior wall of the riser be discharged as a "miscellaneous discharge". Answer: Yes Diverter Systems BOEM regulations at 30CFR250.433(a) require drill rigs to test the diverter system weekly. After the mud in the lines is displaced, minor volumes of fluid could be released while actuating the diverter valves. BOP (from SBM Q&A) Question: The BOP is pumped out and filled with sea water every two weeks. The sea water is used for pressure testing the BOP. The water is then dumped overboard. There will be some SBM residue on the sides of the BOP and small quantities will be dumped overboard with the sea water after the test. Is this small amount of SBM considered a small volume discharge or is it considered "de minimis"? Answer: The SBM discharged during BOP testing is considered "de minimis" since it is a very minor volume and can't be measured. De minimis discharges must be contained to the extent

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
				practicable to prevent discharge.
12	Produced Water	I.B.4.b.3	Revise permit language at Part I.B.4.b.3) "....Samples for monitoring produced water toxicity shall be collected ....before the flow is split from a common source for multiple discharges. If the discharge points have different flows and pipe diameters, the permittee may perform the test on the discharge with the highest calculated critical dilution. For discharges which have discharges with multiple ports that do not meet the vertical separation distance requirements of Table 1-G or that have noncircular ports, the permittee shall calculate port size for tables 1-A through 1-F using an equivalent diameter representative of all openings, and use total flow. Equivalent diameter shall be calculated using : Equivalent Diameter = square root (Atotal * 4/pi), where Atotal is the total area of all discharge openings in question. Samples shall be...."	The proposed language covers past clarifications from EPA as follows: • 3/26/08- Scott Wilson USEPA VI communications with Rob Kuehn, Shell. Clarified when multiple discharges of PW from one treatment train do not need separate tox tests run. Run the tox test on the discharge with the most restrictive critical dilution (a function of pipe diameter and flow). If the test passes on the discharge with the most restrictive (highest) critical dilution then certainly the other discharge would pass as well. • 9/18/07- Scott Wilson USEPA VI communications with Rob Kuehn, Shell. Clarified when a platform has two or more discharge pipes (each pipe with a single discharge opening) that do not meet the vertical separation distances for a "vertical port", the diameter to use for determining Critical Dilution should be the "equivalent" diameter of the two openings. This equivalent diameter along with total flow should be used to determine Critical Dilution. The method converts the total area in question into an equivalent diameter by solving the formula: Diameter = SQRT(Atotal * 4/pi) Example: Pipe A: 4" diameter w/flow = 7,000 bwpd Pipe B: 8" diameter w/flow = 21,000 bwpd An equivalent diameter would be 8.9" and flow would be 28,000 bwpd. • Based on the 9/18/07 clarification, OOC requests the change to address noncircular ports. Noncircular ports may be used to retard scale formation in and around a discharge port.
13	DMR/Reporting	I.D.3.j	"In accordance with Part II.D.4 of this permit, the permittee shall report on the DMR for the reporting period the lowest Whole Effluent Toxicity (i.e., lethal or sub-lethal) values determined for either species for the 30-Day Average Minimum and 7-Day Minimum under Parameter No. 22414..."	Based on communications with Phil Jennings and Robert Houston, EPA R6. C-K Associates 1/2011.The intent was this would be for both lethal and sub-lethal toxicity once sub-lethal became effective. Acknowledged missing language in permit.
14	Produced Water	I.B.4.a. & I.D.3.e	Delete the following from I.B.4.a: ~~Compliance with sub-lethal effects must be achieved within two years after the effective date of this permit.~~ Revise I.D.3.e as follows : If the effluent fails the survival and sub-lethal end points ~~(or the sub-lethal endpoint, after two years from the effective date of this permit)~~ at the critical dilution, the permittee shall be considered in violation of this permit limit.......	This provision covered addition of the sub-lethal endpoint to the 2007 permit limits. It no longer applies.

No.	Type/Category	Permit Section Ref.	Revised Permit Wording/Clarification/Issue	Rationale
15	Sanitary Waste	I.B.7.b	Revise Part I.B.7.b … A grab sample must be taken once per month and the concentration recorded. The approved analytical methods are Hach CN-66-DPD or the EPA method specified in 40 CFR Part 136 for Total Residual Chlorine.	Update HACH test to specify test methods approved in 40 CFR 136 Similar to Region 4 Permit (GEG460000)
16	Misc. Chem. Treated seawater and Freshwater		Intentionally Blank	Sampling sub-sea equipment that contains chemically treated saltwater or freshwater is challenging since one must rely on Remote Operated Vehicles (ROVs) to collect samples at depths in excess of 5000' of water. Permit holders request that EPA allow sampling of sub-sea chemically treated seawater/freshwater discharges by allowing permittees to dilute neat treatment chemicals using laboratory synthetic dilution water to chemical manufacturer's theoretical half-life or % activity based on a function of time since some of these lines/equipment could be treated and sit idle in excess of a year or more before they are ready for service. In addition to ROV sample difficulty collection, the sample holding time is difficult to comply with since samples can take hours to reach the water surface due to the slow ascent required of the sample to prevent over-pressurizing the sample container. In addition to the slow rate of ascent, logistics to transport the sample by helicopter and then ground courier can also impact sample holding time. OOC is not proposing any changes to the permit regarding this issue. OOC is looking at conducting a study on the effects of chemically treated seawater/freshwater dilution and testing of neat treatment chemicals to chemical manufacturer's theoretical half life or activity based on a function of time when adverse sampling conditions exist. The intent of this study will be to develop alternative methods for bench testing chem. Treated waters when sample collection (e.g. subsea) is impossible.